Information Request AG-2-5

Has Dr. Parmesano presented testimony supporting a marginal cost of service study or studies to be used in the design of electric utility rates? If yes, please provide a copy of the studies, the related testimony and the related regulatory commission orders.

Response

Yes. The Company objects to providing copies of all such testimony and studies because it is overly burdensome given the very large number (in excess of 40) of such testimonies provided over the years. However, during the past five years, Dr. Parmesano has presented such testimony only once. A copy of testimony and marginal cost studies for Rochester Gas and Electric in Case 02-E-0198 is attached. The NYPSC's various orders related to this case are available on their website at [http://www3.dps.state.ny.us/pscweb/WebFileRoom.nsf/Page?OpenForm]. See, for example, the March 7, 2003 Order.

D.T.E. 03-121

AG-2-5 (Att. 1)

BULK Attachment

AG-2-5 (Att. 1)

Case No.________
Exhibit #36

ROCHESTER GAS AND ELECTRIC CORPORATION

EXHIBITS OF

HETHIE S. PARMESANO

NATIONAL ECONOMIC RESEARCH ASSOCIATES

February, 2002

HETHIE S. PARMESANO

BUSINESS ADDRESS

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Los Angeles, California 90017
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KEY QUALIFICATIONS

Dr. Hethie Parmesano is an expert on electricity, gas and water industry costing, pricing, structure, and regulation. In recent years she has been involved with projects dealing with regulation, restructuring, and privatization of state-owned utilities in a variety of different settings, including the U.K., Spain, India, Greece, El Salvador, Argentina, Brazil and Mexico. Dr. Parmesano also has extensive experience with costing, pricing and restructuring issues in the U.S. utility industry. Her work both in the U.S. and abroad has involved issues such as regulating distribution companies, metering and settlement for customers with retail access, and pricing of services supplied to competitors of the distribution company. She teaches seminars on costing and pricing topics, directs a NERA-sponsored industry group called the Marginal Cost Working Group, and has testified widely on utility matters before regulatory agencies.

RECENT PROJECTS

- **Direct Service Industries**
  Portland, Oregon
  2001

  Dr. Parmesano assisted the DSIs in their intervention in the rate case of the Bonneville Power Administration, arguing that rates for all consumer groups based on marginal cost prices at the margin (tiered rates) was a superior solution to the problem of high-priced marginal resources than average pricing for all.

- **Public Power Corporation of Greece**
  Athens, Greece
  2001

  Dr. Parmesano led a group of NERA economists in development of a draft Distribution Tariff Code, covering all aspects of distribution tariff setting and line extension policies. The project included preparation of estimates of the marginal costs of electricity distribution in Greece, the distribution company's revenue requirement, and sample marginal cost-based tariffs that produce that revenue requirement.

- **Rochester Gas & Electric Corporation**
  Rochester, New York
  2001

  Dr. Parmesano's group prepared studies of the marginal costs of gas and electric service for RG&E.

- **New York State Electric & Gas Corporation**
  Binghamton, NY
  2000-01

  Dr. Parmesano and her group assisted NYSEG in the development of updated methods for computing marginal costs of electricity service.

- **Large Southern US Electric Utility**
  2001

  Dr. Parmesano led a group of economists in the development of a retail pricing strategy for an investor-owned utility. The strategy will help the company prepare for coming retail access and implementation of an RTO.

- **ANEEL (Brazilian Electricity Regulatory Agency)**
  Brasilia, Brasil
  2000

  Dr. Parmesano directed a NERA team assisting the regulatory commission to develop policies and procedures for setting and revising electricity tariffs for the newly privatized distribution companies in the country.

- **Secretaria de Energia**
  Mexico City, Mexico
  1999-2000

  Dr. Parmesano was part of a NERA team advising the Mexican government on electric industry restructuring. She was director of the Tariffs Task Force for this project.

- **Andrah Pradesh Electricity Regulatory Commission**
  Hyderabad, India
  1999-2000

Dr. Parmesano directed a NERA team providing tariff-related assistance to the newly formed regulatory commission in the state of Andrah Pradesh. Her responsibilities included staff training, development of a tariff philosophy, drafting of tariff filing guidelines and associated commission procedures, and on-site assistance to the commission during its review of the first tariff filed by the transmission and distribution licensee. Her team developed costing and tariff design models for use by the commission and its staff.

- ☐ **Salt River Project**
  Phoenix, Arizona
  1998

  At the request of the Board of Directors of the Salt River Project (SRP), Dr. Parmesano reviewed SRP Management's proposed bundled and unbundled electric price plans and provided recommendations to the Board. The focus of her review was on (1) the proposed class allocations; (2) the proposed price plans; (3) the cost studies on which they are based; and (4) the relationship between the bundled and unbundled prices.

- ☐ **Rochester Gas & Electric Corporation**
  Rochester, New York
  1997

  Dr. Parmesano directed a NERA team that undertook the cost studies and rate design analysis for pricing new services that RG&E will be offering to electricity retailing companies when retail open access is offered. These services include special metering, non-standard billing, and administration of balancing and settlement.

- ☐ **Economic Analysis of Argentinean Electricity Sector: Distribution Tariff and Regulatory Policy**
  Argentina
  1997

  Dr. Parmesano advised the Government of Argentina on ways to improve the operation of the electricity sector, with special emphasis on expansion of retail access, metering and settlement mechanisms, distribution tariffs, retail open access, demand-side management, distortions caused by taxes and subsidies, and quality standards and penalties for distribution concessionaires. This effort was a part of the first formal review - undertaken by NERA - of the structure and functions of the Argentine electricity sector since its radical reform in 1992.

- ☐ **Orissa Electricity Regulatory Commission**
  Orissa, India
  1994-1999

Dr. Parmesano participated on the NERA team responsible for the design and implementation of Orissa Electricity Regulatory Commission, the first independent state regulatory commission in India. The Commission was created as a key part of the overall reform and restructuring of the Orissa electric state power sector. Dr. Parmesano's responsibilities include: organizational design; development of rules and procedures for tariff approval; participation in drafting of enabling legislation; design of regulations and license; design and implementation of on-site regulatory training; on-site consulting on marginal cost analysis and rate design.

- **Privatization of COSERN, Natal, Brazil**
  Banco Brascan
  1997

  Dr. Parmesano was part of a NERA team assisting Banco Brascan to develop a proposed tariff system, efficiency program, and regulatory mechanism to be detailed in the concession contract for the privatization of COSERN, an electric distribution company in northeast Brazil. Her work included analyzing the tariff structure, regulatory policies, and socio-political factors likely to affect revenues of the new firm.

- **Privatization — Presentation for Potential Investors in Electricity Distribution**
  El Salvador
  1997

  Dr. Parmesano participated in a presentation to introduce potential investors to the El Salvadoran electricity sector. The presentation explained the reform program and regulatory structure and discussed areas of concern for investors in privatized distribution companies.

- **Iberdrola – Advice on Restructuring the Spanish Electricity Industry**
  Spain
  1997

  Dr. Parmesano participated on a NERA team advising Iberdrola, a vertically-integrated electric utility in Spain, during the restructuring of the country's electric industry. Dr. Parmesano provided advice on tariff structure, the cost basis for prices, mechanisms for recovery of strandable costs, and regulatory mechanisms. Her work included providing training sessions to Iberdrola staff members.

- **New York State Electric & Gas Corporation**
  Binghamton, New York
  1997

  Dr. Parmesano helped NYSEG develop its retail rate structure applicable when the utility's retail customers are eligible for retail open access. Her work involved testimony before the New York State Public Service Commission.

- **Haryana Power Sector Restructuring, India**

World Bank Project
1994-1995

Dr. Parmesano was a member of the NERA team preparing a major restructuring study of the Haryana State Electricity Board. The study examined all aspects of the power sector and recommended that the Haryana State Electricity Board be broken up into separate generation, transmission, and distribution entities. The project output included a detailed plan for implementing the restructuring proposal.

- ☐ **Los Angeles Department of Water and Power**
  Los Angeles, California
  1991-92

Dr. Parmesano served as principal advisor to the Los Angeles Department of Water and Power in connection with a major restructuring of water rates. Her work involved participating with the Mayor's Blue Ribbon Committee on Water Rate Structure. She attended virtually every meeting of the full committee and its subcommittees, offering advice on costing and rate design. One of her major tasks was to determine whether the rate structures being contemplated by the Committee were likely to cause financial difficulties for the Department. She also prepared a study of the marginal costs of the Los Angeles water system, a modification of which was ultimately used by the Committee to develop its inverted block rate proposal to the Mayor.

EDUCATION

CORNELL UNIVERSITY
Ph.D., Economics, 1973
M.A., Economics, 1971
Received a National Science Foundation Traineeship.
Areas of specialization were economic development, international economics and economic theory.

COLBY COLLEGE
B.A., Economics, Cum Laude, 1968

EMPLOYMENT

NATIONAL ECONOMIC RESEARCH ASSOCIATES, INC. (NERA)

1980-Present — Vice President

Dr. Parmesano has been involved in numerous economic studies for electric, gas and water utilities. She has specialized in issues related to marginal cost pricing, regulatory and electricity industry reform, strategic planning and resource planning. She has been involved in electric industry restructuring efforts in the U.S., U.K. Argentina, Brazil, Spain, El Salvador and India. She has testified in regulatory proceedings in Arizona, California, Colorado, Florida, Idaho, Illinois, Indiana, Iowa, Maine, Maryland, Minnesota, Nevada, New Mexico, New York, Ohio, Oklahoma, Oregon, Texas, Utah, and Alberta and Nova Scotia, Canada. Her responsibilities include teaching a series of seminars on marginal costing for the staffs of electric utilities and regulatory commissions.

LOS ANGELES DEPARTMENT OF WATER AND POWER (LADWP)

1977-1980 Staff Economist

Dr. Parmesano participated in a variety of rate studies and other economic analyses. Her responsibilities included testimony at LADWP's PURPA hearings on electric rates, membership in the California Marginal Cost Pricing Task Force, and participation in environmental impact studies of proposed LADWP actions and projects.

LOS ANGELES CITY PLANNING DEPARTMENT

1973-1977 Economic Analyst

Dr. Parmesano participated in employment and demographic forecasting as well as economic impact analyses of city plans. She was also on the faculty at California State Polytechnic University at Pomona, teaching graduate courses in urban research techniques and computer applications in planning.

TESTIMONIES

Direct testimony regarding the supplemental proposal of the Bonneville Power Administration on behalf of the Direct Service Industries. The Companies on whose behalf this testimony is filed are proposing that BPA adopt a tiered rate structure, with the second tier price set at market price, as a substitute for BPA's proposal to charge a rolled-in average of the cost of energy. Case No. WP-02-E-DS/AL-02, March 2001.

Direct and supplemental testimony before the Public Utilities Commission of Ohio on behalf of Dayton Power & Light Company regarding shopping credits for consumers who choose another supplier of generation services and a forecast of switching rates by consumer category. Case No. 99-EL-__-ETP, March and May 2000.

Rebuttal testimony before the Illinois Commerce Commission on behalf of Illinois Power Company related to the advisability of unbundling revenue cycle services; the appropriate basis for credits for these services, if unbundled; and the role of marginal costs in a world of retail access, February 10, 1999.

Rebuttal and Surrebuttal testimony before the State of Maine Public Utilities Commission on behalf of Central Maine Power Company regarding Investigation of Stranded Costs, Transmission and Distribution Utility Revenue Requirements, and Rate Design, June 26, 1998 and August 31, 1998.

Testimony before the Salt River Project Board of Directors regarding SRP Management's Proposed Electric Price and Service Plan Changes Effective December 31, 1998, October 1, 1998.

Rebuttal testimony before the Public Utility Commission of New Mexico in the Matter of the Commission's Investigation of the Rates for Electric Service of Public Service Company of New Mexico, Case No. 2761, May 6, 1998, regarding electric rate unbundling.

Direct testimony before the Public Utility Commission of New Mexico in the Matter of the Petition of the City of Albuquerque to institute a retail pilot load aggregation program and its request for related approvals, Case No. 2782, April 16, 1998, regarding stranded cost recovery and other aspects of a pilot retail access program.

Testimony before the Public Utility Commission of New Mexico on behalf of Public Service Company of New Mexico, Case No. 2761 to explain the institutional conditions necessary for any reasonable unbundling of PNM's retail electricity rates, November 3, 1997.

Affidavit filed with the New Mexico Supreme Court in Public Service Company of New Mexico vs. the New Mexico Public Utility Commission, Case No. 2761 in support of PNM's request for a writ of mandamus, and request for stay regarding the NMPUC's order that PNM prepare unbundled electricity rates, October 8, 1997.

Direct and Responsive Testimony before the New York Public Service Commission on behalf of New York State Electric & Gas Corporation as part of NYSEG's rate/restructuring filing in compliance with Public Service Commission Opinion and Order 96-12 regarding rate design for retail access, September 27, 1996 and April 21, 1997.

Testimony before the Oregon Public Utility Commission on behalf of Portland General Electric Company - Case UM 827 on methods for estimating the marginal costs of electric utilities, April 7, 1997.

Rebuttal Testimony before the California Public Utilities Commission on behalf of Southern California Gas Company in the Biennial Cost Allocation Proceedings regarding two specific marginal cost issues—inclusion of replacement costs for existing equipment in marginal cost estimates and use of the "new customer only" approach to customer costs, August 8, 1996.

Direct Testimony before the Nova Scotia Utility and Review Board on behalf of Nova Scotia Power Incorporated in the matter of the Public Utilities Act, R.S.N.S. 1989, C. 380, as amended and in the matter of an Application of Nova Scotia Power Incorporated for Approval of Certain Revisions to its Rates, Charges and Regulations; regarding rate restructuring to improve the utility's competitive position, December 11, 1995.

Rebuttal Testimony before the Indiana Utility Regulatory Commission on behalf of Northern Indiana Public Service Company in Cause No. 40125, regarding an experimental real-time pricing tariff for large industrial customers, February 28, 1995.

Rebuttal and Surrebuttal Testimony before the Illinois Commerce Commission, Docket Nos. 94-0134 and 94-0223 on behalf of Illinois Power Company, August 1994 regarding Illinois Power's proposal for a tariff that would allow contracts to prevent residential, commercial and industrial electric customers from choosing an uneconomic municipal by-pass option.

Direct and Rebuttal Testimony before the Public Utility Commission of Texas, Docket No. 12957-TST-17-0 on behalf of Houston Lighting & Power Company, July 1994 regarding Houston Lighting & Power's proposal for a tariff to permit negotiated contracts with electric customers who have uneconomic bypass options.

Testimony and Comments before the Public Service Commission of Nevada, Docket No. 93-11045 on behalf of Nevada Power Company, June 2, 1994 and June 23, 1994 regarding competition, standby rates and environmental externalities in marginal energy costs. (Testimony and Comments were filed, but case settled before hearings.)

Prefiled Rebuttal Testimony before the State of Maine Public Utilities Commission, Docket No. 92-315 on behalf of Central Maine Power Company, August 18, 1993 regarding resource planning, rate structures and avoided cost investigation.

Prefiled Rebuttal Testimony before the Indiana Utility Regulatory Commission in Cause No. 39623 on behalf of Northern Indiana Public Service Company, May 1993, regarding approval of an electric service contract with Omni Forge, Inc.

Direct Testimony before the Public Utilities Commission of Ohio on behalf of the Dayton Power and Light Company, Case No. 92-594-EL-FOR, February 5, 1993 regarding avoided cost study and appropriateness of estimates used in evaluating DSM programs. (Testimony was filed but case settled before hearings.)

Rebuttal and Surrebuttal Testimony before the Illinois Commerce Commission on behalf of Illinois Power Company, Docket No. 91-0335, February 25 and March 30, 1992 regarding marginal costing and marginal cost-based rates.

Direct Testimony before the Public Utilities Commission of Ohio on behalf of Cincinnati Gas and Electric Company, Case No. 91-372-EL-UNC, August 27, 1991 regarding avoided cost pricing.

Direct Testimony before the Public Service Commission of Maryland on behalf of Baltimore Gas and Electric Company, Case No. 8241, Phase II, July 19, 1991 regarding avoided cost pricing.

Expert testimony before the Illinois Commerce Commission, on behalf of Illinois Power Company, Docket No. 89-0276, December 27, 1989 and January 29, 1990 regarding revenue treatment of the differential between regular and economic development rates.

Expert testimony before the Illinois Commerce Commission on behalf of Illinois Power Company, Docket 90-0006, December 8, 1989 regarding marginal cost rate design.

Testimony before the New Mexico Public Service Commission, on behalf of Public Service Company of New Mexico, NMPSC Case 2262, November 1, 1989 and December 8, 1989 regarding marginal costs and incentive energy rates.

Testimony before the State of Maine Public Utilities Commission, on behalf of Central Maine Power Company, Docket No. 89-68, July 31, 1989 regarding marginal costs.

Expert testimony before the State of Maine Public Utilities Commission, regarding Central Maine Power Company's Application for Fuel Cost Adjustment and Establishment of Short-Term Energy-Only Rate for Small Power Producers Less Than 1 MW, on behalf of Central Maine Power Company, Docket No. 89-80, April 14, 1989 regarding energy and capacity components of fuel clause.

Testimony before the Alberta Public Utilities Board and Energy Resource Conservation Board, on behalf of TransAlta Utilities Corporation, Docket No. RE870621, October 1987 regarding independent power producer payments.

Testimony before the Public Service Commission of Utah, on behalf of Utah Power & Light Company, Docket No. 87-035-12, August 17, 1987 regarding marginal costs.

Expert testimony before the Public Service Commission of Nevada, on behalf of Nevada Power Company, Docket No. 86-1201, February 5, 1987 regarding avoided costs.

Expert testimony before the Illinois Commerce Commission, on behalf of Illinois Power Company, in A. E. Staley Manufacturing Co. v. Illinois Power Company, Docket No. 86-0038, September 12, 1986 and November 25, 1986 regarding standby rates.

Expert testimony before the Indiana Public Service Commission, on behalf of Northern Indiana Public Service Company, in Cause No. 38045, June 16, 1986 regarding potential for cogeneration and small power production.

Expert testimony before the Indiana Public Service Commission, on behalf of Northern Indiana Public Service Company, in Cause No. 37863, April 1986 regarding capacity credit formula for qualifying facilities (QF).

Expert testimony before the Maine Public Utilities Commission, on behalf of Central Maine Power Company, in Central Maine Power Company Cost of Service and Rate Design, Docket No. 86-2, February 14, 1986 regarding marginal costs.

Expert testimony on behalf of the Los Angeles Department of Water and Power et al, in the Bonneville Power Administration's 1985 Wholesale Rate Case, November 1984 regarding nonfirm rate design.

Expert testimony before the Superior Court of the State of California for the County of Los Angeles, on behalf of Los Angeles Department of Water and Power, in California Manufacturers' Association, et al. vs. City of Los Angeles, March 1984 regarding marginal cost-based rate restructuring.

Expert testimony on behalf of the Public Service Company of New Mexico, in Docket 1835, before the New Mexico Public Service Commission, February 1984 regarding marginal costs.

Expert testimony on behalf of the Los Angeles Department of Water and Power, et al., in the Bonneville Power Administration's 1983 Wholesale Rate Case, June 1983 regarding nonfirm rate design.

Testimony before the Florida Public Service Commission, on behalf of Metropolitan Dade County, in Docket No. 820406-EU, April and May 1983 regarding QF payments.

Testimony before the Texas Public Utility Commission, on behalf of Houston Lighting and Power Company, in Docket No. 4712, December 1982 regarding avoided costs.

Expert testimony before the Idaho Public Utilities Commission, on behalf of Idaho Power Company, in Case Nos. U-1006-197 and U-1006-200, October 1982 regarding QF payments.

Expert testimony on behalf of the Los Angeles Department of Water and Power, et al., in the Bonneville Power Administration's 1982 Wholesale Rate Case, May 1982 regarding ratemaking objectives.

Expert testimony on behalf of the Los Angeles Department of Water and Power, et al., in the Bonneville Power Administration's 1981 Wholesale Rate Case, February 1982 regarding nonfirm rate design.

Testimony before the Maine Public Utilities Commission, on behalf of Central Maine Power, in Docket No. 80-66, January 1982 regarding marginal cost-based rates.

Expert testimony before the Corporation Commission of the State of Oklahoma on behalf of the Commission, in Cause No. 27208, November 1981 regarding QF payments.

Expert testimony before the Minnesota Public Service Commission on behalf of the State of Minnesota Department of Public Service, in Docket No. E017/6R-81-315, November 1981 regarding marginal costs.

Expert testimony before the Public Service Commission of Utah on behalf of Utah Power & Light Company, in Case No. 80-999-09, March 1981 regarding marginal costs.

Expert testimony before the Colorado Public Utilities Commission on behalf of the City of Aspen, Pitkin County and Windstar Foundation, in Case No. 5970, November 1980 regarding cogeneration.

Testimony before the Idaho Public Utilities Commission on behalf of Utah Power & Light Company, in Case Nos. U-1009-107 and P-300-18, August 1980 regarding marginal cost-based rates.

Expert testimony before the Iowa State Commerce Commission on behalf of the Commission, in Docket No. RMU-80-1, July 1980 regarding marginal cost-based rates.

Expert testimony before the Board of Directors, on behalf of the Board of Directors in the 1980 Salt River Project Electric Rate Case regarding revenue requirement.

Expert testimony before the LADWP Board of Commissioners in LADWP's PURPA hearings, 1980 regarding appropriateness for LADWP's of adoption of PURPA standards.

SELECTED CONSULTING REPORTS

"Review of Comments on NERC Tariff Methodology," January 18, 2001, prepared for National Energy Regulatory Commission of Ukraine.

"DP&L Report on Shopping Incentives," December 1999, prepared for Dayton Power & Light Company.

"An Introduction to System Benefits Charges," May 11, 1998, prepared for The Salt River Project.

"Analysis of the Reform of the Argentine Power Sector: Final Report," January 1998, prepared for the Ministerio de Economía y Obras Servicios Públicos, Secretaría de Energía y Puertos of Argentina.

"Development of RG&E's Fees for New Services," February 19, 1998, prepared for Rochester Gas & Electric Corporation.

"Using Capacity Contracts and Energy Savings To Estimate Marginal Generation Capacity Costs - Contracts: They're Not Just for Lawyers Anymore," October 27, 1997 prepared for the Marginal Cost Working Group.

"Rate Design for Retail Access," October 1, 1996 prepared for the Marginal Cost Working Group.

"Preliminary Evaluation of the Electricity Tariffs of Peninsular Spain," September 16, 1996 prepared for Iberdrola.

"Use of LRIC by the Telecommunication Industry," April 16, 1996 prepared for the Marginal Cost Working Group.

"The Time-Differentiated Marginal Costs of the Orissa State Electricity Board Constituent Companies," February 1996.

"Implications of Retail Wheeling for the State of [Midwestern state]," Confidential, July 1995.

"What is the Marginal Cost of Transmission," April 1995 prepared for the Marginal Cost Working Group.

"Restructuring Study for the Haryana (India) Power Sector Restructuring Project," January 1995 prepared for Haryana State Electricity Board.

"Linking Integrated Resource Planning and Rate Design: Comments on the Tellus Institute's Report for NARUC," October 1994 prepared for the Marginal Cost Working Group.

"The Time-Differentiated Marginal Costs of the Los Angeles Department of Water and Power," November 30, 1993.

"The Time-Differentiated Marginal Costs of Dayton Power and Light Company: A PURPA Study," July 1993.

Co-authored "Dayton Power & Light Company Time-of-Use Study: Preliminary Evaluation," April 14, 1993.

"The Time-Differentiated Marginal Costs of the City of Anaheim Public Utilities Department, Electric Services," December 11, 1992.

"The Marginal Costs of the Los Angeles Department of Water and Power Water System," May 27, 1992.

"The Time-Differentiated Marginal Costs of New York State Electric and Gas Corporation," Revised March 9, 1992.

"The Time-Differentiated Marginal Costs of Public Service Gas and Electric Company," November 22, 1991.

"A&G and General Plant Loaders: Are They Marginal?" April 1991.

"Selection of Efficient Rating Periods," April 1991.

"Empirical Test of the Same-Load-Change vs. Proportional-Load-Change Assumption," April 1990.

"Correct Discount Rate for Use in Economic Carrying Charge Calculation," April 1990.

"The Time-Differentiated Marginal Costs of the Los Angeles Department of Water and Power," September 20, 1989.

"Cut-Off Points in the Differential Revenue Requirements Avoided Cost Method," April 1989.

"The Time-Differentiated Marginal Costs of Public Service Company of Indiana, Inc.," September 19, 1988.

"An Evaluation of the Feasibility of a Common Costing Methodology," Central Maine Power Company, October 28, 1987.

"Report on An Audit of the Resource Planning Activities of the Department of Water and Power of the City of Los Angeles," December 24, 1986.

"Standby Rates for Cogenerators and Small Power Producers," Illinois Power Company, November 15, 1985.

"Avoided Cost Payments for Off-System Qualifying Facilities," San Diego Gas and Electric Company, September 17, 1985.

"A Methodology for Comparative Risk Analysis: Introducing Competition into Avoided Cost Pricing," City of Houston Public Service Department, June 1984.

"Cogeneration in the United States," prepared for Kansai Electric Power Company, Inc., September 1983.

"An Analysis of the Time-Differentiated Marginal Costs of Rochester Gas and Electric Corporation," December 1982.

"An Analysis of Electric Utility Tariffs and Contracts for Cogenerators and Small Power Producers," September 1982.

"An Analysis of the Time-Differentiated Marginal Costs of Central Illinois Light Company," June 1982.

"An Updated Analysis of the Time-Differentiated Marginal Costs of Central Illinois Light Company," prepared for Central Illinois Light Company, December 1981.

"An Updated Analysis of the Time-Differentiated Marginal Costs of Otter Tail Power Company," prepared for the Minnesota Department of Public Service, November 1981.

"An Analysis of the Costs Avoided by Oklahoma Gas and Electric Company When Energy and Capacity are Supplied by Cogenerators and Small Power Producers," prepared for the Oklahoma Corporation Commission, September 1981.

"Summary of Concerns Expressed by Oklahoma Utilities Pertaining to Cogenerators and Small Power Producers," prepared for the Oklahoma Corporation Commission, September 1981.

"Summary of Concerns Expressed by Potential Cogenerators and Small Power Producers in Oklahoma," prepared for the Oklahoma Corporation Commission, August 1981.

"Measuring Avoided Costs for Cogenerators and Small Power Producers," prepared for the Oklahoma Corporation Commission, June 1981.

"An Analysis of the Time-Differentiated Marginal Costs of Central Maine Power Company," prepared for Central Maine Power Company, April 1981.

"Salt River Project Review of Proposed 1981 Rate Increase," prepared for the Board of Directors of the Salt River Project Agricultural Improvement and Power District, December 1980.

"An Analysis of the Time-Differentiated Marginal Costs of Utah Power & Light Company," prepared for the Utah Power & Light Company, October 1980.

"An Analysis of the Time-Differentiated Marginal Costs of Hawaiian Electric Company," prepared for Hawaiian Electric Company, October 1980.

"An Analysis of the Time-Differentiated Marginal Costs of Idaho Power Company," prepared for Idaho Power Company, September 1980.

SELECTED PUBLICATIONS

"An Introduction to Financial Transmission Rights," with Hamish Fraser and Karen Lyons The Electricity Journal, December, 2000.

"Residential Electricity Tariffs: Getting the Structure Right," with Veronica Lambrechts presented at online conference Energy Resource 2000, May 15-29, 2000.

Parmesano, Hethie and Amy McCarthy, "Letter to the Editor: Argument for Embedded Costs Has Basic Flaws." The Electricity Journal (March 1999).

"The Effects of the 1990 Clean Air Act on System Dispatch and Marginal Costs," with Bruce Ambrose and John Wile The Electricity Journal, November 1993.

"The Role and Nature of Marginal and Avoided Costs in Ratemaking: A Survey," NERA Working Paper, February 1992.

"Discount Electric Rates: Who Should Bear the 'Cost'?," with Carrie J. Hightman NERA Working Paper, June 1991.

"Avoided Cost Payments to Qualifying Facilities: Debate Goes On," Public Utilities Fortnightly, September 17, 1987.

Impact of Rate Structure on Demand-Side Management Programs - Phase I Report, EPRI EM 4791, September 1986.

"Comments on John Wender's Article On Class Revenue Requirements," Electric Potential, vol. 1, No. 2, November-December 1985.

"The Evolution in U.S. Electric Utility Design" (with Catherine S. Martin), Annual Energy Review, 1983.

"Pricing the Electrical Output of Cogeneration and Small Power Projects," NERA Topics, October 1983.

RECENT SPEECHES

"Line Extension Policies in the Restructured US Electric Industry," a presentation to the Marginal Cost Working Group (MCWG), Myrtle Beach, SC, April 2001.

"Residential Electricity Tariffs: Getting the Structure Right," a presentation to the Marginal Cost Working Group (MCWG), Santa Fe, NM, October 4-6, 2000.

"Line Extenstion Policies – Due for a Change?" a presentation to the Marginal Cost Working Group (MCWG), Las Vegas, NV, April 3-5, 2000.

"Anitrust Concerns in Retail Access: Learning the Lingo," a presentation to the Marginal Cost Working Group (MCWG), Cambridge, MA, April 27-29, 1998.

"The Role of Securitization of Stranded Costs in a Future Competitive Electric Industry," a presentation to the Conference on Securitization of Electric Utility Stranded Costs, San Francisco, California, October 6, 1997.

"Electric Rate Structure," a presentation to the University of Florida International Training Program on Utility Regulation and Strategy, Florida, January 21, 1997.

"Is Your Contract or Rate Profitable? How Can You Tell?" a presentation to the California Municipal Rates Group, West Hollywood, California, June 25, 1996.

"Alternative Approaches for Area-Specific Marginal Transmission and Distribution Cost Estimation," a presentation to the 1994 EPRI Innovative Pricing Conference, Tampa, Florida, February 11, 1994.

"Marginal Costs: Academic Exercise or Crucial Factor in Electric Utility Decision-Making?" a presentation to the 1993 Annual Meeting of the Canadian Electrical Association, Halifax, Nova Scotia, May 18, 1993.

"Water Rates - Costing for the 90's," a presentation to the California Municipal Rates Group, San Pedro, California, February 16, 1993.

"Implementing a Dynamic Marginal Cost Study at the City of Anaheim," before the American Public Power Association, New Orleans, Louisiana, September 29, 1992.

"Estimating Hourly Marginal Costs," before the California Municipal Rates group, Anaheim, California, January 11, 1990.

"Ratesetting Using Marginal Cost at LADWP," before the California Municipal Rates Group, Winter Meeting, Anaheim, California, January 11, 1990.

Rochester Gas & Electric Corporation

Marginal Cost of Electricity Service

Prepared by

National Economic Research Associates

July 12, 2001

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Rochester Gas & Electric Corporation
Marginal Cost of Electricity Service

I. INTRODUCTION

Rochester Gas & Electric Corporation (RG&E) retained National Economic Research Associates, Inc. (NERA) to prepare an estimate of the company's marginal costs of supplying electricity. This report describes the methods for estimating the generation, transmission, distribution and customer-related components of those costs and presents summary tables of the results.

What are marginal costs? Marginal cost is defined as the change in total cost with respect to a small change in output. To quantify the marginal costs of electricity service one must ask and answer the question: What are the additional costs that would be incurred with changes in kilowatt-hours of energy, kilowatts of demand and number of customers? Because the cost of additional consumption may differ depending upon the time of the change in output, it is important to estimate time-differentiated marginal costs of electricity.

Our method for estimating marginal costs is based on the system planning process. We determine the marginal cost of electricity by examining the utility's planning processes to determine what drives new investment and purchase decisions and how changes in consumption affect system operations. The method is not a formula, but a series of guidelines outlining what should be measured and how the measurements can be made.

II. COSTING/PRICING PERIODS

To the greatest extent possible, we develop *hourly* marginal cost estimates for a typical weekday, Saturday and Sunday for each month. These hourly estimates can be combined to meet the requirements of any marginal cost application; however, to simplify the written report, we have grouped hourly costs by season, using the periods defined in most of RG&E's current time-differentiated rates.[1] The costing periods are as follows:

Summer: June - September

Peak: Monday - Friday, 11 am to 5 pm.

Shoulder: Monday – Friday, 7 am to 11 am; 5 pm to 11 pm

Off-peak: All remaining hours.

Winter: December - February

Peak: Monday – Friday, 5 pm to 9 pm

Shoulder: Monday – Friday, 7 am to 5 pm; 9 pm to 11 pm

Off-peak: All remaining hours.

Base: March – May, October - November

Shoulder: Monday - Friday, 7 am to 11pm

Off-peak: All remaining hours.

III. MARGINAL GENERATION COSTS

A. Conceptual Description

In a competitive electricity market, the marginal cost of generation is the market price. In a market where load-serving entities (LSEs) have no specific capacity obligation, the marginal generation cost of providing an additional kWh in any hour is the spot market price of energy in that hour. In a market (such as the NYISO) where LSEs have an installed capacity requirement, there are two elements of marginal generation cost: (1) If an RG&E customer uses additional energy in a given hour, the marginal energy cost to RG&E is the spot market price in that hour. (2) If the customer's usage changes the amount of capacity RG&E is required to provide according to market rules, the hourly equivalent of the market price of capacity is the marginal capacity cost.

[1] SC-4 and SC-8 RTP have slightly different period definitions.

B. Analysis of RG&E's Marginal Generation Costs

In applying the conceptual framework outlined above to RG&E, we have three specific goals: (1) to determine the marginal energy cost for each hour based on a forecast of spot market prices; (2) to determine the annual market cost of capacity in the NY market and (3) to determine the relative likelihood that load growth in any given hour will increase RG&E's installed capacity requirement.

1. Marginal Energy Costs

RG&E provided a forecast of hourly spot prices at Genesee for the period 2002-2007. The first line of Schedule 1 shows the forecast for 2002, averaged over RG&E's costing periods. These figures represent the market prices at the border of RG&E's service territory. To convert them to marginal costs at customers' meters it is necessary to make two adjustments. First, they must be adjusted for marginal energy losses incurred in moving the energy through RG&E's local transmission and distribution systems. Marginal energy losses increase at each successively lower voltage level. In addition at any given voltage level losses increase with increasing load. Thus there is a different loss adjustment factor for each hour and for each voltage level of service. The derivation of these marginal energy loss factors is described in section VI.E. below.

The second adjustment required is a small factor to account for the cost of financing working capital necessary because RG&E must pay for energy purchases before it is reimbursed by its customers. The cost of financing the balance includes a cost of capital component (RG&E's estimated weighted average cost of capital) and an income tax component that accounts for the fact that the equity portion of the financing is taxable. The marginal energy costs after these two adjustments are shown on the lower portion of Schedule 1. Comparable figures for 2003-2007 are shown in Appendix A.

Schedule 1. 2002 Market Energy Cost Forecast

		Summer Season			Winter Season			Base Season	
		Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak	Shoulder	Off-Peak
		(2001 Dollars per kWh)							
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
(1)	Marginal Energy Costs	$0.0823	$0.0530	$0.0279	$0.0536	$0.0397	$0.0238	$0.0339	$0.0185
	Marginal Energy Costs by Voltage Level, Adjusted for Losses and Working Capital								
(2)	Transmission Service	$0.0828	$0.0533	$0.0281	$0.0539	$0.0399	$0.0240	$0.0341	$0.0186
(3)	Subtransmission Service	0.0842	0.0542	0.0285	0.0548	0.0406	0.0243	0.0346	0.0188
(4)	Subtransmission Secondary Service	0.0845	0.0543	0.0285	0.0550	0.0407	0.0244	0.0347	0.0189
(5)	Primary Service	0.0877	0.0562	0.0293	0.0569	0.0420	0.0250	0.0358	0.0193
(6)	Primary Secondary Service	0.0882	0.0565	0.0294	0.0573	0.0422	0.0251	0.0360	0.0194
(7)	Secondary Service	0.0888	0.0568	0.0295	0.0576	0.0425	0.0252	0.0362	0.0195

2. Capacity Costs

The NYISO requires each transmission district to arrange for installed capacity (ICAP) equal to 17.5 percent (under present rules) of forecast area peak demand. This requirement is allocated among LSEs within the transmission district and adjusted for customer switching from one LSE to another. RG&E's service territory is essentially the same as its transmission district; thus RG&E's ICAP requirement is 17.5 percent of its peak demand.

RG&E provided a semi-annual forecast of the market price of ICAP at Genesee for the years 2002-2007. The monthly prices within years were uniform. Consequently we took the annual cost (2 times the semi-annual costs) times 1.175 as the annual market cost of capacity. This is a price at the RG&E service territory border. Since the transmission district peak hour determines the ICAP requirement, this cost must be adjusted for marginal energy losses through RG&E's subtransmission and distribution systems in the peak hour; an additional kW of consumption by an RG&E customer will increase ICAP requirements by 1 kW plus the additional losses incurred in that hour—marginal energy losses. A second adjustment is required to account for financing of working capital to pay for the marginal capacity, as was the case for marginal energy costs.

3. Hourly Generation Capacity Costs

Additional demand by customers will increase RG&E's ICAP requirement only if that demand falls on the transmission district peak hour. Because the peak hour is not known until after the fact, we estimated the probability of each hour type's being the peak hour, using a statistical analysis of RG&E's hourly system loads over the period 1996-2000.[2] The relative probability of peak of each hour type was then used to assign the annual capacity cost to the hours of the year. These allocation factors are shown in Schedule 2.

Schedule 2. Estimated Relative Probability of Peak

			Relative Probability of System Peak
			(1)
	Summer Season		
(1)		Peak	86%
(2)		Shoulder	14%
(3)		Off-Peak	0%
(4)		Subtotal	100%
	Winter Season		
(5)		Peak	0%
(6)		Shoulder	0%
(7)		Off-Peak	0%
(8)		Subtotal	0%
	Base Season		
(9)		Shoulder	0%
(10)		Off-Peak	0%
(11)		Subtotal	0%
(12)	**Total**		100%

[2] The hour types are hours 1-24 for a typical weekday, Saturday and Sunday of each month.

Although capacity is purchased on a per-MW basis, there is an expected cost in many hours. Therefore, it is appropriate to estimate (and charge for) generation capacity costs on a time-differentiated per-kWh basis. These costs, averaged over the hours within each costing period, are shown on Schedule 3. The figures for the years 2003-2007 are shown on Appendix B.

Schedule 3. 2002 Market Capacity Cost Forecast

		Summer Season			Winter Season			Base Season	
		Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak	Shoulder	Off-Peak
		(2001 Dollars per kWh)							
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
(1)	Marginal Capacity Costs	$0.0400	$0.0039	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
	Marginal Cost to Provide Required Capacity by Voltage Level, Adjusted for Losses and Working Capital								
(2)	Transmission Service	$0.0473	$0.0046	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
(3)	Subtransmission Service	$0.0483	$0.0047	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
(4)	Subtransmission Secondary Service	$0.0485	$0.0047	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
(5)	Primary Service	$0.0508	$0.0050	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
(6)	Primary Secondary Service	$0.0512	$0.0050	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000
(7)	Secondary Service	$0.0516	$0.0050	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000	$0.0000

IV. MARGINAL TRANSMISSION COSTS

Under the rules of the NYISO, RG&E has turned over the planning and operation of its transmission facilities to the ISO. All incremental investment will be made at the request of the ISO and all transmission costs are recovered in a Transmission Service Charge (TSC). Users of the transmission system are required to pay this charge. Thus, the TSC becomes the marginal cost of transmission. We used as the starting point the current and forecast TSC charges, which are flat prices per MWh sold or transported. We adjusted these charges for losses between the RG&E system boundary and customers' meters, using estimates of hourly marginal energy losses, and added an allowance for financing of working capital. Schedule 4 shows the results for 2002. Comparable figures for subsequent years are shown in Appendix C.

Schedule 4. 2002 NYISO Transmission Service Charges

		Summer Season			Winter Season			Base Season	
		Peak	Shoulder	Off-Peak	Peak	Shoulder	Off-Peak	Shoulder	Off-Peak
		(2001 Dollars per kWh)							
		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)
(1)	Marginal Transmission Service Charges	$0.0037	$0.0037	$0.0037	$0.0037	$0.0037	$0.0037	$0.0037	$0.0037
	Marginal Transmission Service Charges by Voltage Level, Adjusted for Losses and Working Capital								
(2)	Transmission Service	$0.0037	$0.0037	$0.0037	$0.0037	$0.0037	$0.0037	$0.0037	$0.0037
(3)	Subtransmission Service	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038
(4)	Subtransmission Secondary Service	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038	0.0038
(5)	Primary Service	0.0039	0.0039	0.0039	0.0039	0.0039	0.0039	0.0039	0.0039
(6)	Primary Secondary Service	0.0040	0.0039	0.0039	0.0040	0.0039	0.0039	0.0039	0.0039
(7)	Secondary Service	0.0040	0.0040	0.0039	0.0040	0.0040	0.0039	0.0039	0.0039

V. MARGINAL DISTRIBUTION COSTS

A. Conceptual Description

Conceptually, most costing practitioners agree that the design of the distribution system is determined by two major factors: (1) the number and location of customers and (2) their demands. Utility cost studies, both marginal and embedded, have traditionally attempted to identify a portion of distribution costs as customer-related and the remaining portion as demand-related. This has led to semantics arguments about the definition of the customer-related and demand-related components. In fact, for most distribution systems, there is no economic reason for this split. Distribution systems (up to the feeder coming from the distribution substation) are typically built using engineering design standards that take into consideration the number of customers and the expected maximum loads of those customers. An area with all-electric homes has different design standards from an area where the homes are not big electricity users. Distribution facilities for commercial and industrial customers are generally designed on a case-by-case basis, given the expected peak load of the customer. In short, the local distribution system is designed based on the design load of the customers to be served, not specifically on the number of customers or their actual loads at any given moment. Trunkline feeders and distribution substations, however, are sized based on near-term peak demands. Thus these costs are marginal with respect to added loads in hours when load is close to capacity.

Because the local marginal distribution costs are incurred based on the design load of the customer, and do not vary with the customer's actual peak load from month to month, it makes sense to recover these marginal distribution costs in a fixed monthly charge imposed on the customer's design load (or actual peak in the past twelve months as a possible proxy). Likewise, since these costs are not saved if a customer chooses to invest in a demand-side management device or a more efficient appliance, it is important to keep these costs out of the usage-sensitive components of marginal or avoided cost estimates. To avoid confusion, we refer to these costs as marginal distribution facilities costs, since the costs are both customer- and (design) demand-related.

The marginal cost of trunkline feeders and distribution substations, which we refer to as demand-related costs, does belong in the usage portion of rates. If a customer uses more in an hour when its distribution substation is peaking, additional capacity will likely be required. If the customer reduces usage in such an hour, capacity if freed up for use by other customers.

B. Distribution Substation and Trunkline Feeder Investment

To estimate the marginal cost of typical substation and trunkline feeder expansion per kW of demand, we asked RG&E engineers to identify the growth-related projects of this type budgeted for the period 2001-2005. Only the costs (in 2001 dollars) associated with growth were used. We then computed the additional capacity these facilities will provide. Dividing the incremental investment by the incremental capacity would give a cost per kW of capacity; however, for a marginal cost study we need a cost per kW of demand. So the capacity figures were adjusted downwards for an assumed 20-percent reserve margin. A kW of additional demand at a time when the substation's capacity is tight will trigger more than a kW of incremental capacity in order to maintain the necessary reserves. The marginal investment is shown on Schedule 5.

Schedule 5. Distribution Substation and Trunkline Feeder Investment

(1)	Investment in Growth-Related Additions to Distribution Substation Plant, 2001-2005 (Thousands of 2001 Dollars)	$35,787
(2)	Estimated Additions to Distribution Substation Non-coincident Peak Load, 2001-2005 (MVA)	397.62
(3)	Marginal Investment in Growth-Related Distribution Substation Facilities per Non-Coincident Kilowatt (2001 Dollars) (1) / (2)	$90.00

The substation and trunkline feeder annual costs (discussed in Section VIII.A. below) must be adjusted for demand losses (discussed in section VI.E. below) and time-differentiated. Ordinarily we assign the annual costs to hours using relative probability of distribution substation peaks, based on a statistical analysis of hourly loads on a sample of substations over several years. Because RG&E does not have machine-readable hourly load information for substations, we used RG&E's system hourly loads for the years 1996-2000, adjusted for the higher carrying capability of this equipment in cold temperatures. The period assignment factors are shown on Schedule 2.[3] The substation and trunkline feeder costs are heavily concentrated in the summer peak period

C. Distribution Facility Investment

In a prior marginal cost study RG&E developed estimates of the investment in secondary lines, transformers, and a portion of primary lines for various types and sizes of customers. The residential analysis was based on new installations for apartments, townhouses and single-family subdivisions over the period 1989-1993. The installed costs were divided by number of customers to derive a typical investment per customer. The results for the three types of residential housing were averaged using weights from the 1989-1993 period. We updated these figures to 2001 dollars.

[3] There was no difference (at the percent level) in the probability of peak with and without the temperature adjustment.

RG&E's earlier analysis for non-residential customers was based on a review of the installed cost of customer-related facilities for a sample of customers of various sizes in each non-residential category, over the period 1989-1991. We also relied upon these figures and simply updated them to 2001 dollars. Street lighting and area lighting loads are assumed to be off-peak and, therefore, not contributing to design demands. So there is no distribution facilities investment for these customer categories.

The distribution facilities investment per customer for residential and non-residential customers is shown on Schedule 6.

Schedule 6. Marginal Distribution Facilities Investment

		Customer Class	Average Investment per Customer (1996 Dollars) (1)	Average Investment per Customer (2001 Dollars) (1) / 0.91 (2)
(1)	SC 1	Residential	$1,153.56	$1,268.92
(2)	SC 2	General Service Small	1,153.56	1,268.92
(3)	SC 3	General Service - 100 kW Min.	8,272.15	9,099.36
(4)	SC 4	Residential - TOU	1,153.56	1,268.92
(5)	SC 7	General Service - 12 kW Min.	7,001.67	7,701.84
	SC 8	Large General Service TOU		
(6)		Transmission	37,956.74	41,752.42
(7)		Subtransmission	31,630.62	34,793.68
(8)		Transmission Secondary	54,314.64	59,746.10
(9)		Primary	6,592.85	7,252.13
(10)		Secondary	16,455.16	18,100.67
(11)	SC 9	General Service TOU	7,001.67	7,701.84

D. Meter and Service Investment

RG&E supplied the current installed cost of a typical meter and service for each customer category. These customer-related distribution marginal investments, stated in 2001 dollars, are shown on Schedule 7.

Schedule 7. Investment per Customer in Meters and Services

	Rate	Description	Service & Meter Investment (2001 $ per Customer) (1)
(1)	SC 1	Residential Service	$617.31
(2)	SC 2	General Service Small	617.31
(3)	SC 3	General Service - 100 kW Min.	3,520.18
(4)	SC 4	Residential - TOU	1,220.18
(5)	SC 7	General Service - 12 kW Min.	1,221.37
	SC 8	Large General Service TOU	
(6)		Transmission	50,864.00
(7)		Subtransmission	12,830.00
(8)		Transmission Secondary	1,107.00
(9)		Primary	3,072.00
(10)		Secondary	1,606.18
(11)	SC 9	General Service TOU	3,620.18

E. Street Lighting Investment

RG&E provided marginal streetlight and area light investment (lamps, fixtures and associated facilities) per lamp and weighted averages for SC 1 and SC 6 in 2001 dollars. The marginal investment by streetlight category is shown on Schedule 8.

Schedule 8. Lighting Investment

		Street Lighting SC 1 Marginal Investment Per Lamp	Area Lighting SC 6 Marginal Investment Per Lamp
		---------- 2001 Dollars ----------	
		(1)	(2)
(1)	Lamp	$11.40	$239.48
(2)	Fixture	552.30	102.64
(3)	Facilities	287.80	118.54
(4)	Total	851.50	460.66

F. Distribution Operation and Maintenance Expenses

Distribution O&M expenses depend on the amount of plant in service. The addition of distribution facilities to meet increments in customers or design load or peak substation load gives rise to increased O&M expenses as well. Distribution O&M expenses are, therefore, marginal costs. Because detailed O&M budgets are not available, we used RG&E's average level of distribution O&M expenses in the recent past as a guide for estimating marginal O&M costs. Expenses for individual components (e.g., meters, substations, etc.) were allocated a proportional share of the general overhead O&M categories.[4]

Relative meter O&M costs, along with their associated overheads, were estimated for each customer class based on weighting factors in a previous RG&E study. Distribution substation O&M, plus associated overheads, was divided by estimates of the sum of non-coincident peak demands at the substations. The O&M costs for local distribution facilities were developed on a per weighted customer basis, using the assumption that O&M is proportional to distribution facilities investment for each customer group. O&M for street lighting was developed on a per lamp basis.

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[4] These general accounts consist of Operation Supervision and Engineering, Miscellaneous Operating Expense, Maintenance Supervision and Engineering, and Miscellaneous Maintenance Expense. No overheads were allocated to street lighting O&M because this function is performed largely by outside contractors who provide their own supervision.

We examined the pattern of each type of O&M expense over the past six years and, after discussions with RG&E, selected an average of years likely to be representative of future levels of marginal expenses. The annual values for meters and facilities O&M were multiplied by the customer class weights to give annual costs by class. Substation O&M is presented on Schedule 9, distribution facilities O&M on Schedules 10 and 11, meter O&M on Schedules 12 and 13, and street lighting O&M on Schedule 14.

Schedule 9. Distribution Substation O&M Expense per kW

	Year	Total Distribution Substation Expenses (Thousand Dollars)	Estimated Substation Noncoincident Peak Loads (MW)	Substation Expenses Per kW of Substation Noncoincident Peak Loads (Dollars)	Weighted Labor and Materials Cost Index (2001=1.00)	Substation Expenses Per kW of Substation Noncoincident Peak Loads (2001 Dollars)
		(1)	(2)	(1) / (2) (3)	(4)	(3) / (4) (5)
(1)	1995	$4,915.97	1,618	$3.04	0.86	$3.53
(2)	1996	5,079.72	1,481	3.43	0.88	3.89
(3)	1997	4,724.89	1,613	2.93	0.90	3.25
(4)	1998	5,802.83	1,576	3.68	0.92	3.98
(5)	1999	7,141.20	1,627	4.39	0.95	4.63
(6)	2000	5,784.90	1,552	3.73	0.97	3.86
(7)	Estimated Annual Distribution Substation O&M Expenses for the Planning Period (Average of 1998-2000)					$4.16

Schedule 10. Distribution Facilities O&M Expense per Weighted Customer

	Year	Distribution Facilities O&M Expenses (000's Dollars)	Average Number of Customers	Weighted Average Number of Customers	Distribution Facilities Expense Per Weighted Customer (Dollars)	Weighted Labor and Materials Cost Index (2001 = 1.00)	Distribution Facilities Expense Per Weighted Customer (2001 Dollars)
				(2) x 1.16	[(1) x 1000]/(3)		(4)/(5)
		(1)	(2)	(3)	(4)	(5)	(6)
(1)	1995	$14,504.25	339,988	394,386	$36.78	0.86	$42.69
(2)	1996	15,189.04	341,282	395,887	38.37	0.88	43.51
(3)	1997	17,961.09	342,902	397,766	45.15	0.90	50.11
(4)	1998	17,438.06	342,836	397,690	43.85	0.92	47.43
(5)	1999	20,454.67	344,375	399,475	51.20	0.95	53.99
(6)	2000	25,268.80	354,992	411,791	61.36	0.97	63.53
(7)	Estimated Annual Weighted Distribution Facilities O&M Expense for the Planning Period (Average of 1999-2000)						$58.76

Schedule 11. Distribution Facilities O&M Expense by Customer Class

	Rate	Class	Weighting Factor ^1	Annual Distribution Facilities Expense Per Customer (2001 Dollars) (1) x $58.76 ^1
			(1)	(2)
(1)	SC 1	Residential	1.00	$58.76
(2)	SC 2	General Service Small	1.00	58.76
(3)	SC 3	General Service - 100 kW Min.	7.17	421.31
(4)	SC 4	Residential - TOU	1.00	58.76
(5)	SC 7	General Service - 12 kW Min.	6.07	356.67
	SC 8	Large General Service TOU		
(6)		Transmission	32.90	1,933.20
(7)		Subtransmission	27.42	1,611.20
(8)		Transmission Secondary	47.08	2,766.42
(9)		Primary	5.72	336.11
(10)		Secondary	14.26	837.92
(11)	SC 9	General Service TOU	6.07	356.67

Note:
^1 Schedule 10, Line 7: $58.76

Schedule 12. Meter O&M Expense per Weighted Customer

	Year	Total Meter Operation & Maintenance Expenses (000's Dollars)	Average Number of Customers	Weighted Average Number of Customers	Meter Expense Per Weighted Customer (Dollars)	Weighted Labor and Materials Cost Index (2001 = 1.00)	Meter Expense Per Weighted Customer (2001 Dollars)
				(2) x 1.26	[(1) x 1000]/(3)		(4)/(5)
		(1)	(2)	(3)	(4)	(5)	(6)
(1)	1995	$1,346.47	339,988	428,385	$3.14	0.86	$3.65
(2)	1996	1,561.09	341,282	430,015	3.63	0.88	4.12
(3)	1997	1,373.73	342,902	432,057	3.18	0.90	3.53
(4)	1998	4,207.53	342,836	431,973	9.74	0.92	10.54
(5)	1999	2,182.14	344,375	433,913	5.03	0.95	5.30
(6)	2000	2,266.08	354,992	447,290	5.07	0.97	5.25
(7)	Estimated Annual Weighted Meter O&M Expense for the Planning Period (Average of 1999-2000)						$5.27

Schedule 13. Meter O&M Expense by Customer Class

	Rate	Class	Weighting Factor	Annual Meter Expense Per Customer
				(2001 Dollars)
				(1) x $5.27 ^1
			(1)	(2)
(1)	SC 1	Residential	1.00	$5.27
(2)	SC 2	General Service Small	1.43	7.54
(3)	SC 3	General Service - 100 kW Min.	7.60	40.05
(4)	SC 4	Residential - TOU	1.39	7.33
(5)	SC 7	General Service - 5 kW Min.	5.87	30.93
	SC 8	Large General Service TOU		
(6)		Transmission	61.47	323.95
(7)		Subtransmission	50.46	265.92
(8)		Transmission Secondary	40.24	212.06
(9)		Primary	39.45	207.90
(10)		Secondary	28.66	151.04
(11)	SC 9	General Service TOU	16.25	85.64

Note:
^1 Schedule 12, Line 7: $5.27

Schedule 14. Lighting O&M Expense

		Street Lighting SC 1	Area Lighting SC 6
		Marginal Maintenance Expense Per Lamp	Marginal Maintenance Expense Per Lamp
		-------------- 2001 Dollars ------------------	
		(1)	(2)
(1)	Lamp	$4.57	$22.27
(2)	Fixture	0.00	0.00
(3)	Facilities	0.00	0.00
(4)	Total	4.57	22.27

VI. OTHER MARGINAL COSTS

A. Customer Accounts Expenses

Customer accounts expenses, composed mainly of meter-reading and billing expenses, are costs that are directly attributable to the existence of customers on the system. Two sub-accounts, (903.72 and 903.73) both Information Systems expense categories, are fixed in the very short-term with respect to the number of customers being metered and billed, and therefore, they were excluded from the analysis.

As shown on Schedule 15, we analyzed the level of these expenses for the last six years and settled on the assumption that the average value in the period 1998 to 2000 is a reasonable proxy for the marginal cost in future years. Annual expenses were divided by weighted customers to obtain a customer accounts expense per weighted customer. The weighted number of customers was derived by multiplying the number of customers in each class by a factor reflecting the relative cost responsibility of each class for each sub-account, as measured by allocators such as number of customers, or revenue.

Schedule 15. Customer Accounts Expense per Weighted Customer

		1995	1996	1997	1998	1999	2000
		(1)	(2)	(3)	(4)	(5)	(6)
(1)	Customer Accounts Expenses (Thousand Dollars)	$19,302.48	$20,109.12	$19,813.39	$15,462.59	$18,313.47	$16,112.41
(2)	Number of Customers	339,988	341,282	342,902	342,836	344,375	354,992
(3)	Weighted Customers (2) x 1.51	513,382	515,336	517,782	517,682	520,006	536,038
(4)	Expense per Weighted Customer (Dollars) [(1) / (3)] x 1000	$37.60	$39.02	$38.27	$29.87	$35.22	$30.06
(5)	Labor Cost Index (2001=1.00)	0.84	0.86	0.89	0.92	0.94	0.97
(6)	Expense Per Weighted Customer in 2001 Dollars (4) / (5)	$44.89	$45.24	$43.07	$32.64	$37.36	$30.96
(7)	Estimated Annual Expense Per Weighted Customer For the Planning Period (2001 Dollars) (Average of 1998-2000)	----------	----------	$33.65	----------	----------	----------

We developed the customer accounts expense for each major customer class as shown on Schedule 16 by multiplying the class weight by the expense per weighted customer on Schedule 15.

Schedule 16. Customer Accounts Expense by Customer Class

	Rate	Class	Weighting Factor	Annual Customer Accounts Expense Per Customer (2001 Dollars) (1) x $33.65 ^1
			(1)	(2)
(1)	SC 1	Residential Service	1.00	$33.65
(2)	SC 2	General Service Small	1.09	36.53
(3)	SC 3	General Service - 100 kW Min.	26.68	897.88
(4)	SC 4	Residential - TOU	1.74	58.42
(5)	SC 6	Area Lighting Service	0.74	24.84
(6)	SC 7	General Service - 12 kW Min.	5.96	200.39
	SC 8	Large General Service TOU		
(7)		Transmission	122.14	4,110.18
(8)		Subtransmission	122.14	4,110.18
(9)		Transmission Secondary	122.14	4,110.18
(10)		Primary	122.14	4,110.18
(11)		Secondary	122.14	4,110.18
(12)	SC 9	General Service TOU	7.17	241.23
(13)	SL	Street Lighting	12.69	427.07

Note:
^1 Schedule 15, Line (7): $33.65

B. Customer Service and Informational Expenses

Customer service and informational expenses, which include the costs of disseminating information to consumers, vary with the number of customers on the system and are, therefore, marginal. We identified a number of sub-accounts that are not marginal with respect to number of customers; these were deleted from our computations.[5]

[5] The sub-accounts deleted are: Marketing Supervision (909.06), All Other Customer Initiatives (910.00), Customer Assistance – Consumer Relations (910.05), Customer Assistance – Marketing (910.06), Customer Assistance – Builders (910.09), Customer Assistance – Area Development (910.10), all the Informational

As Schedule 17 shows, we analyzed the level of these expenses for the last five years and settled on the assumption that the average value in the period 1999-2000 is a reasonable proxy for the marginal cost in future years. Annual expenses were divided by weighted customers to obtain a customer accounts expense per weighted customer.

Schedule 17. Customer Informational and Service Expense per Weighted Customer

		1995	1996	1997	1998	1999	2000
		(1)	(2)	(3)	(4)	(5)	(6)
(1)	Customer Service and Informational Expenses (Thousand Dollars)	$10,170.08	$4,043.19	$1,276.77	$5,862.71	$4,934.73	$5,620.17
(2)	Customers	339,988	341,282	342,902	342,836	344,375	354,992
(3)	Weighted Number of Customers (2) x 13.16	4,473,942	4,490,970	4,512,288	4,511,419	4,531,671	4,671,380
(4)	Expense Per Weighted Customer (Dollars) [(1) / (3)] x 1000	$2.27	$0.90	$0.28	$1.30	$1.09	$1.20
(5)	Labor Cost Index (2001 = 1.00)	0.84	0.86	0.89	0.92	0.94	0.97
(6)	Expense Per Weighted Customer in 2001 Dollars (4) / (5)	$2.71	$1.04	$0.32	$1.42	$1.16	$1.24
(7)	Estimated Annual Expense Per Weighted Customer For the Planning Period (2001 Dollars) (Average of 1999-2000)	----------------	----------------	$1.20	----------------	----------------	----------------

The same procedure used for customer accounts expenses was followed to develop weights and generate annual expenses for each major customer class, which are shown on Schedule 18.

Advertising sub-accounts (911.01-911.10), Information System Hardware, Software Maintenance (912.72) and Information System In-house Systems and Programming (912.73).

Schedule 18. Customer Informational and Service Expense by Customer Class

	Rate	Class	Weighting Factor	Annual Customer Service and Informational Expense Per Customer (2001 Dollars)
				(1) x $1.20 ^1
			(1)	(2)
(1)	SC 1	Residential Service	1.00	$1.20
(2)	SC 2	General Service Small	13.24	15.89
(3)	SC 3	General Service - 100 kW Min.	854.33	1,025.20
(4)	SC 4	Residential - TOU	3.09	3.71
(5)	SC 6	Area Lighting Service	1.76	2.11
(6)	SC 7	General Service - 12 kW Min.	138.62	166.34
	SC 8	Large General Service TOU		
(7)		Transmission	2,403.62	2,884.34
(8)		Subtransmission	2,403.62	2,884.34
(9)		Transmission Secondary	2,403.62	2,884.34
(10)		Primary	2,403.62	2,884.34
(11)		Secondary	2,403.62	2,884.34
(12)	SC 9	General Service TOU	191.58	229.90
(13)	SL	Street Lighting	3.99	4.79

Note:
^1 Schedule 17, Line (7): $1.20

C. Administrative and General Expenses

Based on our understanding of RG&E's classification of costs in the various FERC accounts for administrative and general (A&G) expenses (including social security and unemployment taxes), we divided these expenses into two categories: (1) those associated with other types of expenses and (2) those associated with plant. We discarded accounts not likely to be marginal with respect to other expenses or plant.[6] We then used regression analyses on 10 years of historical data (1991-2000) to estimate the marginal level of non-plant-related A&G expense. Non-plant-related A&G expense in constant dollars was regressed on total O&M (less production-related expenses, wheeling costs and total A&G), all in constant dollars. The coefficient of the explanatory variable, 0.32, is the loader. It implies that every dollar spent on distribution O&M, for example, results in a $0.32 expenditure on A&G.

The only marginal element of plant-related A&G is property insurance. We computed a property insurance loader as the expected 2002 insurance premium per dollar of investment amounts of these types of plant. RG&E's property insurance covers distribution substations and general plant, but not lines or other distribution facilities. Both loaders are shown on Schedule 19.

D. General Plant

General plant consists of items such as office buildings, warehouses, cars, trucks and other equipment. When a utility adds transmission and distribution equipment, its need for general plant increases as well. We used regression analysis on 10 years of historical company data (1991-2000) to estimate a marginal general plant loader applicable to distribution plant. Cumulative additions to general plant (plus the electric portion of common plant) were regressed on cumulative additions to generation plant and cumulative additions to transmission plus distribution plant, all in constant dollars. The coefficient for the T&D explanatory variable, shown on Schedule 19, is the loader applicable to marginal distribution plant.

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[6] We discarded the following accounts: Account 925, Injuries and Damages, is probably marginal, but the values in the account fluctuate from year to year due to reserve adjustments and claim payments, and so the historical levels do not provide a good benchmark for future marginal levels. Account 930.1, General Advertising Expense, is not marginal. Account 930.2, Miscellaneous General Expenses was omitted because this account is erratic and we could not determine whether it is likely to be marginal.

Schedule 19. Administrative and General and General Plant Loaders

		Estimate of Loading Factor
	Administrative and General Expenses and Social Security and Unemployment Taxes	
(1)	Applicable to Non-plant-Related Expenses ^1	31.66%
(2)	Applicable to Plant-Related Expenses ^2	0.04%
(3)	General Plant & the Electric Share of Common Plant ^3	18.56%

Notes:

^1 Regressed Non-Plant-Related A&G Accounts on Total Operation and Maintenance Expenses Excluding Fuel and Purchase Power, Total A&G and Account 565 Transmission by Others, all in constant dollars.

NW2_NPLNTAG	=	0.3166 TEXPLESS
t-Statistic		(32.09)
Standard Error		(0.009867)

Root MSE = 5,647,804 R^2 = 0.9931 N = 10 D.F. = 9

^2 The cost to include a new substation in the existing property insurance policy (3.5 cents per hundred dollars) today raised by the expected increase of 20% in insurance costs for 2002.

^3 Regressed cumulative additions to general and the electric share of common plant (ADDGEN) on cumulative additions to power production plant (CAPP), and transmission and distribution plant (CATDP).

ADDGEN	=	-116,120,000	+	0.0912 CAPP	+	0.1856 CATDP
t-Statistic		(-2.27)		(2.30)		(3.52)
Standard Error		(51,265,913)		(0.0397)		(0.0527)

Root MSE = 5,579,161 R^2 = 0.9750 N = 10 D.F. = 7

E. Marginal Losses

The marginal loss calculations in this study are based on variable and total losses at time of system peak at each voltage level for which costs are calculated. Marginal capacity losses applied to distribution substation and trunkline feeder costs reflect the fact that, to accommodate a kW of additional peak load at the customer's meter, facilities must be expanded by successively more than a kW as you move upstream to accommodate the fixed and variable losses on the system in the peak hour. Peak capacity loss factors were developed from RG&E's most recent available loss study.

Marginal energy losses reflect the additional losses incurred to move an added kWh through the system at a particular level of system load. Fixed losses are, by definition, not affected by the increments in load. Only variable losses come into these calculations. Marginal energy losses increase in proportion to the square of the load. We calculated hourly losses by means of an approximation of quadratic losses based on variable losses at system peak load and the year 2000 hourly loads. These marginal energy losses were applied to the hourly market price forecast and transmission service charges, and the results are shown on Schedules 1 and 4.

VII. COMPUTATION OF CARRYING CHARGES

Section V. above describes the development of estimates of marginal investment in several categories of distribution plant. To be useful in ratemaking and other marginal cost applications, the investment costs must be converted into annual costs using an economic carrying charge. These annual charges reflect the elements of RG&E's revenue requirement associated with incremental plant: return to stockholders and bondholders, depreciation, and taxes.

For use in a marginal cost study, the appropriate stream of annual charges is a stream that rises at the rate of inflation net of technical progress and yields the total present value of all costs over the life of the investment. In such a stream, the first year's charge represents the cost in today's dollars of having the plant or equipment for a year. It also represents the rental rate for such an investment in a competitive market.

A key element of the carrying charge computation is RG&E's expected incremental capital structure and cost. RG&E foresees financing of incremental investment through sales of common stock, preferred stock and debt over the study period.

	Share %	Cost %
Common Stock	46.23	11.0
Preferred Stock	4.46	5.24
Debt	49.31	7.10

An integral part of the economic carrying charge calculation is the estimation of the rate of inflation net of technical progress applicable over the life of the investment. While it is never easy to peg an exact rate of future inflation or technical progress, we used the geometric mean of a GDP price index forecast for 2001 to 2010, provided by RG&E.

Another component of the economic carrying charge is an adjustment for the fact that not all plant and equipment will last its estimated service life. Some components will require early replacement, causing added costs, while some will last longer than expected and produce savings. The pattern of expected required replacement for each type of plant is defined by an Iowa Curve. An adjustment for this dispersed pattern of replacements using Iowa Curves was included in the derivation of the economic carrying charges. The results of these economic carrying charge calculations are presented on Schedule 20.

Schedule 20. Economic Carrying Charges

		Distribution Substation (1)	Distribution Facilities (2)	Meters (3)	Street Lights (4)
(1)	Present Value of Revenue Requirements Related to Incremental $1,000 Investment	$1,497.09	$1,486.99	$1,480.17	$1,442.09
(2)	Present Value Cost of Replacing Dispersed Retirements Related to Incremental $1,000 Investment	$108.37	$108.88	$80.73	$86.31
(3)	Total Present Value Cost Related to Incremental $1,000 Investment (1)+(2)	$1,605.46	$1,595.87	$1,560.90	$1,528.40
(4)	First-Year Annual Economic Charge Related to Incremental $1,000 Investment ^1	$89.52	$94.97	$103.50	$128.71
(5)	First-Year Annual Economic Charge Related to Incremental Investment [(4)/$1,000]	8.95%	9.50%	10.35%	12.87%

Note:
^1 The appropriate charge is the first-year charge which rises annually at the rate of inflation net of technological progress. The first-year charge is calculated using the following formula:

$$AC_T = K(R - J)(1 + J)^{T-1} \left[\frac{1}{1 - \left[\frac{1 + J}{1 + R}\right]^N} \right]$$

where:
AC_T = Annual Charge in Year T
T = Year Index (T = 1)
K = Total PV of Revenue Requirement for Original Investment [line (3)]
R = Discount Rate (After-tax incremental cost of capital)
J = Inflation Rate Net of Technical Progress
N = Book Life

VIII. COMPUTATION OF ANNUAL MARGINAL COSTS

The next step of the study was to apply the economic carrying charges to the marginal investment costs and add the associated expenses.

A. Distribution Substations and Trunkline Feeders

The unit investment for distribution substations and trunkline feeders was adjusted upwards by the general plant loading factor. We multiplied the resulting figures by the annual economic carrying charge percentage plus the plant-related A&G loading factor to yield the annualized plant costs. To these costs we added the associated O&M and A&G expenses and the revenue requirements for working capital. The computation of working capital includes cash, materials, supplies and prepayments. The working capital needs were estimated based on recent historical amounts. The revenue requirement for this working capital was developed from RG&E's weighted average cost of capital plus an income tax component that recognizes that the equity portion of return on capital is taxable. Schedule 21 presents the total annual marginal cost per kW calculations for distribution substations and trunkline feeders.

Schedule 21. Derivation of Annual Distribution Substation and Trunkline Feeder Costs

(1)	Marginal Investment per kW	$90.00
(2)	With General Plant Loading (1) x 1.1856	106.70
(3)	Annual Economic Carrying Charge Related to Capital Investment	8.95%
(4)	A&G Loading (plant related)	0.04%
(5)	Total Annual Carrying Charge (3) + (4)	8.99%
(6)	Annualized Costs (2) x (5)	$9.60
(7)	O&M Expenses	4.16
(8)	With A&G Loading (7) x 1.3166 (Non-plant Related)	5.48
(9)	Demand-Related Cost (6) + (8)	$15.07
	Working Capital	
(10)	Material and Supplies (2) x 0.22%	$0.23
(11)	Prepayments (2) x 0.32%	0.34
(12)	Cash Working Capital Allowance (8) x 4.68%	0.26
(13)	Total Working Capital (10) + (11) + (12)	0.83
(14)	Revenue Requirement for Working Capital (13) x 12.52%	$0.10
(15)	Total Annual Marginal Cost per kW	$15.18

B. Distribution Facilities

The same annualization procedure used for distribution substations was applied to distribution facilities costs. The result is annual distribution facilities costs by customer type as shown on Schedules 22 (I) and 22 (II).

Schedule 22. Derivation of Annual Distribution Facilities Costs (I)

		SC 1 Residential	SC 2 General Service Small	SC 3 General Service 100 kW Min	SC 4 Residential TOU	SC 7 General Service 12 kW Min.
		(2001 Dollars per Customer)				
		(1)	(2)	(3)	(4)	(5)
(1)	Marginal Investment per customer	$1,268.92	$1,268.92	$9,099.36	$1,268.92	$7,701.84
(2)	With General Plant Loading (1) x 1.1857 ^1	1,504.53	1,505.06	10,792.74	1,505.06	9,135.13
(3)	Annual Economic Carrying Charge Related to Capital Investment	9.50%	9.50%	9.50%	9.50%	9.50%
(4)	A&G Loading (plant-related)	0.00%	0.00%	0.00%	0.00%	0.00%
(5)	Total Annual Carrying Charge (3) + (4)	9.50%	9.50%	9.50%	9.50%	9.50%
(6)	Annualized Costs (2) x (5)	142.88	142.93	1,024.97	142.93	867.55
(7)	Annual Expense per Weighted Customer	58.76	58.76	421.31	58.76	356.67
(8)	With A&G Loading (7) x 1.3166 (non-plant related)	77.36	77.36	554.70	77.36	469.59
(9)	Distribution Facilities Related Costs (6) + (8)	220.25	220.30	1,579.67	220.30	1,337.14
	Working Capital					
(10)	Material and Supplies (2) x 0.22%	3.31	3.31	23.74	3.31	20.10
(11)	Prepayments (2) x 0.32%	4.81	4.82	34.54	4.82	29.23
(12)	Cash Working Capital Allowance (8) x 4.68%	3.62	3.62	25.96	3.62	21.98
(13)	Total Working Capital (10) + (11) + (12)	11.75	11.75	84.24	11.75	71.31
(14)	Revenue Requirement for Working Capital (13) x 12.52%	1.47	1.47	10.55	1.47	8.93
(15)	Total Annual Marginal Distribution Facilities Related Costs (9) + (14)	221.72	221.77	1,590.22	221.77	1,346.07

Note:

^1 The loader includes the property insurance loading factor of 0.0004 for general plant.

Schedule 22. Derivation of Annual Distribution Facilities Costs (II)

			SC 8	SC 8	SC 8	SC 8	SC 8	SC 9
			Large General Service TOU Transmission	Large General Service TOU Subtransmission	Large General Service TOU Subtransmission Secondary	Large General Service TOU Primary	Large General Service TOU Secondary	General Service TOU
			(2001 Dollars per Customer)					
			(1)	(2)	(3)	(4)	(5)	(6)
(1)	Marginal Investment per customer		$41,752.42	$34,793.68	$59,746.10	$7,252.13	$18,100.67	$7,701.84
(2)	With General Plant Loading (1) x 1.1857	^1	49,504.92	41,254.10	70,839.64	8,598.70	21,461.57	9,131.90
(3)	Annual Economic Carrying Charge Related to Capital Investment		9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
(4)	A&G Loading (plant-related)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(5)	Total Annual Carrying Charge (3) + (4)		9.50%	9.50%	9.50%	9.50%	9.50%	9.50%
(6)	Annualized Costs (2) x (5)		4,701.41	3,917.85	6,727.54	816.61	2,038.18	867.24
(7)	Annual Expense per Weighted Customer		1,933.20	1,611.20	2,766.42	336.11	837.92	356.67
(8)	With A&G Loading (7) x 1.3166 (non-plant related)		2,545.25	2,121.31	3,642.27	442.52	1,103.21	469.59
(9)	Distribution Facilities Related Costs (6) + (8)		7,246.67	6,039.15	10,369.81	1,259.13	3,141.38	1,336.84
	Working Capital							
(10)	Material and Supplies (2) x 0.22%		108.91	90.76	155.85	18.92	47.22	20.09
(11)	Prepayments (2) x 0.32%		158.42	132.01	226.69	27.52	68.68	29.22
(12)	Cash Working Capital Allowance (8) x 4.68%		119.12	99.28	170.47	20.71	51.63	21.98
(13)	Total Working Capital (10) + (11) + (12)		386.45	322.05	553.00	67.14	167.53	71.29
(14)	Revenue Requirement for Working Capital (13) x 12.52%		48.38	40.32	69.24	8.41	20.97	8.93
(15)	Total Annual Marginal Distribution Facilities Related Costs (9) + (14)		7,295.05	6,079.47	10,439.05	1,267.54	3,162.36	1,345.76

Note:
^1 The loader includes the property insurance loading factor of 0.0004 for general plant.

C. Meter, Service and Customer-Related Costs

The annual unit costs for meters, services and customer-related expenses was developed using a procedure similar to that for the other types of plant. These results are presented by customer category on Schedules 23 (I) and 23 (II).

Schedule 23. Derivation of Annual Meter, Service and Customer-Related Costs (I)

			SC 1 Residential	SC 2 General Service Small	SC 3 General Service 100 kW Min	SC 4 Residential TOU	SC 7 General Service 12 kW Min
			(2001 Dollars per Customer)				
			(1)	(2)	(3)	(4)	(5)
(1)	Investment per Customer in Services & Meters		$617.31	$617.31	$3,520.18	$1,220.18	$1,221.37
(2)	With General Plant Loading (1) x 1.1857	^1	731.94	731.94	4,173.80	1,446.74	1,448.15
(3)	Annual Economic Charge Related to Capital Investment		10.35%	10.35%	10.35%	10.35%	10.35%
(4)	A&G Loading (Plant Related)		0.00%	0.00%	0.00%	0.00%	0.00%
(5)	Total (3) + (4)		10.35%	10.35%	10.35%	10.35%	10.35%
(6)	Annualized Costs (2) x (5)		75.76	75.76	431.99	149.74	149.88
(7)	Meter O&M Expenses		5.27	7.54	40.05	7.33	30.93
(8)	Customer Accounts Expenses		33.65	36.53	897.88	58.42	200.39
(9)	Customer Service and Informational Expenses		1.20	15.89	1,025.20	3.71	166.34
(10)	With A&G Loading [(7)+(8)+(9)] x 1.3166 (Non-plant Related)		52.82	78.94	2,584.66	91.45	523.56
(11)	Customer-Related Costs (6) + (10)		128.58	154.70	3,016.64	241.19	673.44
	Working Capital						
(12)	Materials and Supplies (2) x 0.22%		1.61	1.61	9.18	3.18	3.19
(13)	Prepayments (2) x 0.320%		2.34	2.34	13.36	4.63	4.63
(14)	Cash Working Capital (10) x 4.68%		2.47	3.69	120.97	4.28	24.50
(15)	Revenue Requirement for Working Capital [(12)+(13)+(14)] x 12.52%		0.80	0.96	17.97	1.51	4.05
(16)	Total Annual Marginal Customer-Related Costs (11) + (15)		129.38	155.66	3,034.61	242.70	677.49

Notes:

^1 The loader includes the property insurance loading factor of 0.0004 for general plant.

Schedule 23. Derivation of Annual Meter, Service and Customer-Related Costs (II)

			SC 8 Large General Service TOU Transmission	SC 8 Large General Service TOU Subtransmission	SC 8 Large General Service TOU Subtransmission Secondary	SC 8 Large General Service TOU Primary	SC 8 Large General Service TOU Secondary	SC 9 General Service TOU
			(2001 Dollars per Customer)					
			(1)	(2)	(3)	(4)	(5)	(6)
(1)	Investment per Customer in Services & Meters		$50,864.00	$12,830.00	$1,107.00	$3,072.00	$1,606.18	$3,620.18
(2)	With General Plant Loading (1) x 1.1857	^1	60,308.32	15,212.25	1,312.55	3,642.40	1,904.41	4,292.37
(3)	Annual Economic Charge Related to Capital Investment		10.35%	10.35%	10.35%	10.35%	10.35%	10.35%
(4)	A&G Loading (Plant Related)		0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
(5)	Total (3) + (4)		10.35%	10.35%	10.35%	10.35%	10.35%	10.35%
(6)	Annualized Costs (2) x (5)		6,241.90	1,574.46	135.85	376.99	197.11	444.26
(7)	Meter O&M Expenses		323.95	265.92	212.06	207.90	151.04	85.64
(8)	Customer Accounts Expenses		4,110.18	4,110.18	4,110.18	4,110.18	4,110.18	241.23
(9)	Customer Service and Informational Expenses		2,884.34	2,884.34	2,884.34	2,884.34	2,884.34	229.90
(10)	With A&G Loading [(7)+(8)+(9)] x 1.3166 (Non-plant Related)		9,635.50	9,559.10	9,488.18	9,482.71	9,407.84	733.04
(11)	Customer-Related Costs (6) + (10)		15,877.40	11,133.56	9,624.03	9,859.69	9,604.95	1,177.30
	Working Capital							
(12)	Materials and Supplies (2) x 0.22%		132.68	33.47	2.89	8.01	4.19	9.44
(13)	Prepayments (2) x 0.320%		192.99	48.68	4.20	11.66	6.09	13.74
(14)	Cash Working Capital (10) x 4.68%		450.96	447.39	444.07	443.81	440.31	34.31
(15)	Revenue Requirement for Working Capital [(12)+(13)+(14)] x 12.52%		97.23	66.30	56.48	58.03	56.41	7.20
(16)	Total Annual Marginal Customer-Related Costs (11) + (15)		15,974.63	11,199.86	9,680.52	9,917.72	9,661.36	1,184.50

Notes:
^1 The loader includes the property insurance loading factor of 0.0004 for general plant.

D. Streetlighting Costs

Schedule 24 shows the annual costs per luminaire applicable to street lighting and area lighting customers.

Schedule 24. Derivation of Annual Lighting Costs

			"SC 1" Street Lights	"SC 2" Street Lights	"SC 3" Street Lights	SC 6 Area Lights
			---------- (2001 Dollars per Unit)	----------	----------	----------
			(1)	(2)	(3)	(4)
(1)	Marginal Investment per Light		$851.50	n/a	n/a	$460.66
(2)	With General Plant Loading (1) x 1.1857	^1	1,009.60	n/a	n/a	546.19
(3)	Annual Economic Carrying Charge Related to Capital Investment		12.87%	n/a	n/a	12.87%
(4)	A&G Loading (plant-related)		0.00%	n/a	n/a	0.00%
(5)	Total Annual Carrying Charge (3) + (4)		12.87%	n/a	n/a	12.87%
(6)	Annualized Costs (2) x (5)		129.95	n/a	n/a	70.30
(7)	Annual Expense per Unit		4.57	n/a	n/a	22.27
(8)	With A&G Loading (7) x 1.3166 (non-plant related)		6.01	n/a	n/a	29.32
(9)	Subtotal (6) + (8)		135.96	n/a	n/a	99.62
	Working Capital					
(10)	Material and Supplies (2) x 0.22%		2.22	n/a	n/a	1.20
(11)	Prepayments (2) x 0.32%		3.23	n/a	n/a	1.75
(12)	Cash Working Capital Allowance (8) x 4.68%		0.28	n/a	n/a	1.37
(13)	Total Working Capital (10) + (11) + (12)		5.73	n/a	n/a	4.32
(14)	Revenue Requirement for Working Capital (13) x 12.52%		0.72	n/a	n/a	0.54
(15)	Total Annual Costs per Unit (9) + (14)		136.68	n/a	n/a	100.17

Note:
^1 The loader includes the property insurance loading factor of 0.0004 for general plant.

IX. SUMMARY SCHEDULES

Schedule 25 summarizes the monthly marginal customer and distribution facilities costs by customer class. Both of these cost elements are not time-differentiated because these costs are independent of the timing of a customer's usage. The distribution facilities costs are shown on a per customer basis, but they could be computed and charged on the basis of each customer's own design demand, rather than on the class average design demand.

Schedule 25. Summary of Monthly Marginal Customer and Distribution Facilities Costs

		Customer Class	Monthly Distribution Facilities Marginal Unit Costs	Monthly Marginal Customer Unit Costs	Total Monthly Costs
			---------- 2001 Dollars per Customer		----------
					(1) + (2)
			(1)	(2)	(3)
(1)	SC 1	Residential	$18.48	$10.78	$29.26
(2)	SC 2	General Service Small	18.48	12.97	31.45
(3)	SC 3	General Service - 100 kW Min.	132.52	252.88	385.40
(4)	SC 4	Residential - TOU	18.48	20.23	38.71
(5)	SC 7	General Service - 12 kW Min.	112.17	56.46	168.63
	SC 8	Large General Service TOU			
(6)		Transmission	607.92	1,331.22	1,939.14
(7)		Subtransmission	506.62	933.32	1,439.94
(8)		Transmission Secondary	869.92	806.71	1,676.63
(9)		Primary	105.63	826.48	932.10
(10)		Secondary	263.53	805.11	1,068.64
(11)	SC 9	General Service TOU	112.15	98.71	210.86

Schedule 26 summarizes 2002 marginal energy, ICAP, transmission and distribution substation costs per kWh by period. Schedule 27 shows the same information, but the substation costs are stated on a per-kW basis instead of a per kWh basis. Schedule 28 summarizes the annual and monthly costs for street lighting and area lighting customers.